6. CO_2 Capture, Storage, and Transport

6.1 CO_2 Capture

The EPA Platform v6 2022 Reference Case (EPA Platform v6) allows for the building of potential (new) Ultra-Supercritical Coal (USC) and Natural Gas Combined Cycle (NGCC) Electric Generating Units (EGUs) with Carbon Capture and Storage (CCS) technology.[58] CCS is also available as a retrofit option to existing coal-fired and NGCC EGUs.

6.1.1 CO_2 Capture for Potential EGUs

Potential USC EGUs are provided with two CCS options, namely, a 30-percent carbon dioxide (CO_2) capture efficiency option and a 90-percent CO_2 capture efficiency option. Potential NGCC EGUs, on the other hand, are provided with only the 90-percent CO_2 capture efficiency option. The CCS cost and performance assumptions provided in Table 6-1 are based on the Annual Energy Outlook 2021 (AEO 2021). The assumptions represent an amine-based, post-combustion CO_2 capture system.

Table 6-1 Cost and Performance Assumptions for Potential USC and NGCC with and without Carbon Capture in v6

	Combined Cycle - Single Shaft	Combined Cycle - Multi Shaft	Combined Cycle with CCS	Ultra-supercritical Coal without CCS	Ultra-supercritical Coal with 30% CCS	Ultra-supercritical Coal with 90% CCS
Size (MW)	418	1083	377	650	650	650
First Year Available	2028	2028	2030	2028	2030	2030
Lead Time (Years)	3	3	3	4	4	4
Availability	87%	87%	87%	85%	85%	85%
Vintage #1 (2028)						
Heat Rate (Btu/kWh)	6,431	6,370	7,124	8,638	9,751	12,507
Capital (2019$/kW)	1,007	891	2,358	3,454	4,303	5,572
Fixed O&M (2019$/kW/yr)	13.99	12.10	27.38	40.27	53.87	59.08
Variable O&M (2019$/MWh)	2.53	1.86	5.79	4.46	7.02	10.89
Vintage #2 (2030)						
Heat Rate (Btu/kWh)	6,431	6,370	7,124	8,638	9,751	12,507
Capital (2019$/kW)	977	864	2,268	3,334	4,147	5,363
Fixed O&M (2019$/kW/yr)	13.99	12.10	27.38	40.27	53.87	59.08
Variable O&M (2019$/MWh)	2.53	1.86	5.79	4.46	7.02	10.89
Vintage #3 (2035)						
Heat Rate (Btu/kWh)	6,431	6,370	7,124	8,638	9,751	12,507
Capital (2019$/kW)	905	800	2,060	3,050	3,780	4,870
Fixed O&M (2019$/kW/yr)	13.99	12.10	27.38	40.27	53.87	59.08
Variable O&M (2019$/MWh)	2.53	1.86	5.79	4.46	7.02	10.89
Vintage #4 (2040)						
Heat Rate (Btu/kWh)	6,431	6,370	7,124	8,638	9,751	12,507
Capital (2019$/kW)	845	747	1,883	2,810	3,469	4,450
Fixed O&M (2019$/kW/yr)	13.99	12.10	27.38	40.27	53.87	59.08
Variable O&M (2019$/MWh)	2.53	1.86	5.79	4.46	7.02	10.89
Vintage #5 (2045)						
Heat Rate (Btu/kWh)	6,431	6,370	7,124	8,638	9,751	12,507
Capital (2019$/kW)	789	698	1,719	2,587	3,180	4,061
Fixed O&M (2019$/kW/yr)	13.99	12.10	27.38	40.27	53.87	59.08
Variable O&M (2019$/MWh)	2.53	1.86	5.79	4.46	7.02	10.89
Vintage #6 (2050)						
Heat Rate (Btu/kWh)	6,431	6,370	7,124	8,638	9,751	12,507
Capital (2019$/kW)	732	648	1,556	2,361	2,889	3,672
Fixed O&M (2019$/kW/yr)	13.99	12.10	27.38	40.27	53.87	59.08
Variable O&M (2019$/MWh)	2.53	1.86	5.79	4.46	7.02	10.89
Vintage #7 (2055)						
Heat Rate (Btu/kWh)	6,431	6,370	7,124	8,638	9,751	12,507
Capital (2019$/kW)	732	648	1,556	2,361	2,889	3,672

[58] The term carbon capture refers to removing CO_2 from the flue gases emitted by fossil fuel-fired EGUs.

	Combined Cycle - Single Shaft	Combined Cycle - Multi Shaft	Combined Cycle with CCS	Ultra-supercritical Coal without CCS	Ultra-supercritical Coal with 30% CCS	Ultra-supercritical Coal with 90% CCS
Fixed O&M (2019$/kW/yr)	13.99	12.10	27.38	40.27	53.87	59.08
Variable O&M (2019$/MWh)	2.53	1.86	5.79	4.46	7.02	10.89

6.1.2 CO_2 Capture for Existing EGUs with CCS retrofit

As noted, EPA Platform v6 offers the option of adding CCS to existing coal-fired and NGCC EGUs as a retrofit option. The option comes with a CO_2 capture efficiency of 90 percent. As in the case of potential EGUs with CCS, the CO_2 capture assumptions for CCS retrofit represent an amine-based, post-combustion CO_2 capture system.

The cost and performance assumptions provided in Table 6-2 are based on the Sargent & Lundy[59] cost algorithm (Attachment 6-1 summarizes the study). One issue that must be addressed when installing an amine-based, post-combustion CO_2 capture system is that sulfur oxides (e.g., sulfur dioxide (SO_2) and sulfur trioxide (SO_3)) in the EGU flue gas can degrade the amine-based solvent that absorbs the CO_2. Since the amine will preferentially absorb SO_2 before CO_2, it will be necessary to treat the EGU flue gas to lower the sulfur oxide concentration to 10 parts per million by volume or less. Meeting this constraint will require installing a supplemental Wet Flue Gas Desulfurization (FGD) technology or retrofitting an existing FGD. However, **existing FGDs are not retrofitted in v6. The supplemental FGDs are also not implemented in the v6.**

Table 6-2 Performance and Unit Cost (2019 $) Assumptions for Carbon Capture in v6

Technology	Capacity (MW)	Heat Rate (Btu/kWh)	Capital Cost $/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)[2]	Capacity Penalty (%)	Heat Rate Penalty (%)
Coal Steam	400	9,000	1,915	27.9	4.3	27.6	38.1
		10,000	2,222	31.3	5.0	30.7	44.3
		11,000	2,557	35.0	5.8	33.7	50.9
	700	9,000	1,915	23.9	4.3	27.6	38.2
		10,000	2,222	27.2	5.0	30.7	44.3
		11,000	2,557	30.7	5.8	33.8	51.0
	1,000	9,000	1,915	22.3	4.3	27.6	38.2
		10,000	2,222	25.5	5.0	30.7	44.3
		11,000	2,557	28.9	5.8	33.8	50.9
Combined Cycle	400	7,000	1,043	18.1	1.7	15.2	18.0
		8,000	1,223	20.0	2.0	17.4	21.1
		9,000	1,414	22.1	2.3	19.6	24.4
	700	7,000	1,043	14.7	1.7	15.2	18.0
		8,000	1,224	16.6	2.0	17.4	21.1
		9,000	1,414	18.5	2.3	19.6	24.4
	1,000	7,000	1,043	13.3	1.7	15.2	18.0
		8,000	1,224	15.2	2.0	17.4	21.1
		9,000	1,414	17.1	2.3	19.6	24.4

Note:
[1]Incremental costs are applied to the derated (i.e., after retrofit) capacity.
[2]The CO_2 Transportation, Storage, and Monitoring portion of the variable O&M has been removed from Sargent & Lundy cost method and modeled separately.

[59] Sargent & Lundy. "*IPM Model – Updates to Cost and Performance for APC Technologies – CO_2 Reduction Retrofit Cost Development Methodology.*" Project 13527-002; January 2023.

The capacity-derating penalty and associated heat rate penalty are an output of the Sargent & Lundy model. (See Section 5.1.1 for further details.)

6.2 CO_2 Storage

The capacity and cost assumptions for CO_2 storage in EPA Platform v6 2022 Reference Case are the same as in the EPA Platform v6 Summer 2021 Reference Case. The assumptions are based on the Geosequestration Cost Analysis Tool (GeoCAT) - a spreadsheet model developed for the U.S. EPA by ICF in support of the U.S. EPA's Underground Injection Control (UIC) Program for CO_2 Geologic Storage Wells.[60] In an earlier version of the EPA Platform v6, the EPA Platform v6 November 2018 Reference Case, ICF updated the major cost components in the GeoCAT model, including revising onshore and offshore injection and monitoring costs to reflect 2016 industry drilling, equipment, and service costs.[61] In addition to updating costs, ICF updated storage capacity, well injectivity, and other assumptions by state and offshore area using data from the research program conducted at DOE/NETL. Assumptions for the amount of carbon dioxide injected for enhanced oil recovery (EOR) was updated using 1972 to 2016 performance data for U.S. carbon dioxide miscible flood projects.

The GeoCAT model combines detailed characteristics of sequestration capacity by state and geologic setting for the U.S. with costing algorithms for individual components of CO_2 geologic sequestration. The model outputs are regional sequestration cost curves that indicate how much potential storage capacity is available at different lifecycle CO_2 storage cost points in units of dollars per metric ton stored.

The GeoCAT model includes three modules:

i) A unit cost specification module
ii) A project scenario costing module
iii) A geologic and regional cost curve module

The unit cost specification module includes data and assumptions for 120 cost elements falling within the following categories:

i) Geologic site characterization
ii) Area of review and corrective action (including fluid flow and reservoir modeling during and after injection and identification, evaluation, and remediation of existing wells within the area of review)
iii) Injection well and other facilities construction
iv) Well operation
v) Monitoring the movement of CO_2 in the subsurface
vi) Mechanical integrity testing
vii) Financial responsibility (to maintain sufficient resources for activities related to closing and remediation of the site)
viii) Post injection site care
ix) Site closure
x) General and administrative

[60] Federal Requirements Under the UIC Program for CO_2 Geologic Sequestration Wells, Federal Register, December 10, 2010 (Volume 75, Number 237), pages 77229-77303.

[61] The major data sources for updating costs was the Bureau of Labor Statistics (BLS) Producers Price Index (PPI) for various products and services related to oil and gas well drilling (https://www.bls.gov/ppi/), the "Joint Association Survey of Drilling Costs" published by the American Petroleum Institute (http://www.api.org/products-and-services/statistics#tab_overview), and the "Well Cost Study" published by the Petroleum Services Association of Canada (https://www.psac.ca/resources/well-cost-study-overview/).

Of the ten cost categories for geologic CO_2 sequestration listed above, the largest cost drivers (in roughly descending order of magnitude) are well operation, injection well and other facilities construction, and monitoring the movement of CO_2 in the subsurface. The cost estimates are consistent with the requirements for geologic storage facilities under the UIC Class VI rule[62] and Greenhouse Gas (GhG) Reporting Program Subpart RR[63]. The price of oil assumed for the calculation of EOR economics is $75/barrel.

The costs derived in the unit cost specification module are used in the GeoCAT project scenario costing module to develop commercial scale costs for eight sequestration scenarios compliant with UIC Class VI standards and GhG Reporting Program Subpart RR:

i) Deep saline formations
ii) Depleted gas fields
iii) Depleted oil fields
iv) Enhanced oil recovery
v) Enhanced coal bed methane recovery
vi) Enhanced shale gas
vii) Basalt storage
viii) Unmineable coal seams

EPA's GeoCAT application for CO_2 sequestration includes only storage capacity for the first four sequestration scenarios. The last four reservoir types are not included because they are not considered technically mature enough to allow CO_2 storage in the foreseeable future.

The current GeoCAT model includes the DOE analysis of the lower-48 states CO_2 sequestration capacities from the "Carbon Sequestration Atlas of the United States and Canada Version 5."[64] ICF enhanced these assessments to include additional details needed for economic modeling such as the distribution of capacity by state, drilling depth, injectivity, etc. The geologic and regional cost curve module applies regionalized unit cost factors to these geologic characterizations to develop regional geologic storage cost curves.[65] The analysis of storage volumes is carried out by regional carbon sequestration partnerships as overseen by NETL in Morgantown, West Virginia. State-level onshore and offshore capacity volumes are reported for storage in oil and gas reservoirs and deep saline formations. The great majority of storage volume is in deep saline formations, which are present in many states and in most states with oil and gas production. In the version of the Atlas used here, offshore storage volumes have also been broken out by DOE into the Gulf of Mexico, Atlantic, and Pacific Outer Continental Shelf (OCS) regions. ICF carried out a separate analysis to break out CO_2 EOR storage potential from the total potential in oil and gas reservoirs reported in NATCARB.

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[62] *Supra* Note 59.

[63] Title 40 of the Code of Federal Regulations (CFR), Part 98 (Mandatory GhG Reporting), Subpart RR (Geologic Sequestration of CO_2). See https://ecfr.io/Title-40/sp40.23.98.rr.

[64] Carbon Sequestration Atlas of the United States and Canada – Version 5 (2015), U.S. Department of Energy, National Energy Technology Laboratory, Morgantown, WV https://www.netl.doe.gov/research/coal/carbon-storage/atlasv. Accessed mid-October 2016 with data updates through 2015.

[65] Detailed discussions of the GeoCAT model and its application for EPA can be found in U.S. Environmental Protection Agency, Office of Water, "Geologic CO_2 Sequestration Technology and Cost Analysis, Technical Support Document" (EPA 816-B-08-009) June 2008, https://www.epa.gov/sites/production/files/2015-07/documents/support_uic_co2_technologyandcostanalysis.pdf and Harry Vidas, Robert Hugman and Christa Clapp, "Analysis of Geologic Sequestration Costs for the United States and Implications for Climate Change Mitigation," Science Digest, Energy Procedia, Volume 1, Issue 1, February 2009, Pages 4281-4288. Available online at https://www.sciencedirect.com/science/article/pii/S1876610209008832.

Efficiency Assumptions for EOR Uses of CO_2

Relying on performance data from 1972 to 2016, the geologic storage cost curve for EOR is based on an average EOR efficiency of 10 thousand cubic feet of CO_2 per incremental barrel of crude oil (Mcf/bbl). The NETL CO_2 EOR Primer[66] shows that from the start of CO_2 floods in 1972 to 2008 the average efficiency was 7.66 Mcf/bbl. Data for the most recent seven year has shown a lower average efficiency of over 10.32 Mcf/bbl. Taken together, the data implies an average of 8.62 Mcf/bbl for all years from 1972 to 2016.

Historical CO_2 EOR: 1972-2008	
Billion cubic feet of CO_2	11,000
Million barrels of crude oil	1,437
Mcf/barrel	7.66
Source: NETL, "Carbon Dioxide Enhanced Oil Recovery", 2010	
Historical CO_2 EOR: 2009-2016	
Billion cubic feet of CO_2	8,339
Million barrels of crude oil	808
Mcf/barrel	10.32
Source: ICF estimates based on EPA GHG Inventory and Oil & Gas Journal Annual EOR Survey	
Historical CO_2 EOR: 1972-2016	
Billion cubic feet of CO_2	19,339
Million barrels of crude oil	2,244
Mcf/barrel	8.62
Source: Sum of prior two tables	

The average of all historical and ongoing EOR projects through the end of their lifetimes is likely to exceed 9.0 Mcf/bbl as they continue to operate at ratios above 10 Mcf/bbl.[67] ICF has chosen a calibration point of 10 Mcf/bbl for the average of potential future CO_2 EOR under the belief that the quality of future projects would likely be worse (i.e., require more CO_2 per unit of incremental oil production) than historical projects. The revised average efficiency value of 10 Mcf/bbl is approximately 15 percent higher than the original version of GeoCAT, which was calibrated to the older historical data.

The results of the project scenario costing module are taken as inputs into the geologic and regional cost curve module of GeoCAT, which generates national and regional cost curves indicating the volume of sequestration capacity in each region and state in the U.S. as a function of total cost per ton of CO_2 including all capital and operating costs. The result is a database of sequestration capacity by state, geologic reservoir type, and cost step.

Table 6-3 shows the NATCARB V storage volumes for the U.S. Lower-48 as allocated to GeoCAT categories. Total Lower-48 capacity is assessed at 8,216 gigatonnes. There are no volumes in the current model for potential storage in depleted gas field reservoirs because these are not reported in NATCARB.

For EPA Platform v6, GeoCAT represents storage opportunities in 37 of the lower 48 continental states.[68] Louisiana and Texas have both onshore and offshore state-level storage cost curves. In

[66] National Energy Technology Laboratory, "Carbon Dioxide Enhanced Oil Recovery", 2010, https://www.netl.doe.gov/file%20library/research/oil-gas/CO2_EOR_Primer.pdf

[67] For example, assuming an average of 10 years of future operation at the 2016 ratios leads to a lifetime average for all historical and ongoing CO_2 EOR project of 9.09 Mcf/bbl.

[68] The states without identified storage opportunities in EPA Platform v6 are Connecticut, Iowa, Maine, Massachusetts, Minnesota, Nevada, New Hampshire, New Jersey, Rhode Island, Vermont, and Wisconsin. These

addition, because NATCARB does not provide state-level data, there are multi-state Atlantic offshore and Pacific offshore storage cost curves. The result is 41 storage cost curves shown in Table 6-4.

Table 6-3 Lower-48 CO_2 Sequestration Capacity by Region (Gigatonnes) in v6

					Offshore Allocation in GeoCAT					
		Onshore	Offshore	Total	Louisiana	Texas	GOM Total	Pacific	Atlantic	Total
CO2 Enhanced Oil Recovery	Low	11.2	1.1	12.3						
	Mid	**15.0**	**1.5**	**16.4**	**1.5**	**0.0**	**1.5**	**0.0**	**0.0**	**1.5**
	High	22.5	2.2	24.7						
Depleted Oil	Low	128.0	11.8	139.8						
	Mid	**170.7**	**15.7**	**186.4**	**12.7**	**3.0**	**15.7**	**0.1**	**0.0**	**15.7**
	High	256.0	23.6	279.6						
Unmineable Coal	Low	47.8	2.0	49.8						
	Mid	**63.7**	**2.6**	**66.4**	**0.0**	**0.0**	**0.0**	**2.6**	**0.0**	**2.6**
	High	95.6	4.0	99.5						
Saline	Low	4,252	1,708	5,960						
	Mid	**5,669**	**2,277**	**7,947**	**1,240**	**798**	**2,038**	**37**	**202**	**2,277**
	High	12,477	3,416	15,893						
Totals	Low	4,439	1,723	6,162						
	Mid	**5,919**	**2,297**	**8,216**	**1,254**	**801**	**2,055**	**40**	**202**	**2,297**
	High	12,851	3,446	16,297						
Oil Subtotal	Low	139.2	12.9	152.1						
(EOR plus Depleted Oil Flds.)	**Mid**	**185.6**	**17.2**	**202.8**	**14.16**	**2.97**	**17.13**	**0.05**	**0.00**	**17.18**
	High	278.5	25.8	304.2						

Note: Individual values may not sum to reported totals due to rounding.

The cost curves in Table 6-4 are in the form of step functions. In any given year within the IPM model, a specified amount of storage is available at a particular step price until either the annual storage limit or the total storage capacity is reached. In determining whether the total storage capacity has been reached, the model tracks the cumulative storage used up through the current year. Once the cumulative storage used equals the total storage capacity at that price step, no more storage is available going forward at that particular step price and, so, higher priced steps must be used.

CO_2 storage opportunities are relevant not just to power sector sources, but also to sources in other industrial sectors. Therefore, before being incorporated as a supply representation into EPA Platform v6, the original CO_2 storage capacity in each storage region was reduced by an estimate of the storage that would be occupied by CO_2 generated by other industrial sector sources at the relevant level of cost effectiveness (represented by $/ton CO_2 storage cost).

To do this, ICF first estimated the level of industrial demand for CO_2 storage in each CO_2 storage region in a scenario where the value of abating CO_2 emissions is assumed to be $50 per ton (this abatement value is relevant not only to willingness to pay for storage but also for the cost of capture and transportation of the abated CO_2).[69] The quantity of industrial sequestration economic at $50/ton represent the "high quality" industrial sources that have high CO_2 purity and would be easiest to capture, rehydrate, and compress. They are made up of ethanol plants, hydrogen production at

states were either not assessed or were found to not have storage opportunities in NATCARB for the four sequestration scenarios included in EPA's inventory, (i.e., deep saline formations, depleted gas fields, depleted oil fields, and enhanced oil recovery).

[69] The approach that ICF employed to estimate industrial demand for CO_2 storage is described in ICF International, "Methodology and Results for Initial Forecast of Industrial CCS Volumes," January 2009.

refineries and merchant plants and gas processing plants where CO_2 is removed from the natural gas. This amount was calculated as 128 million tons per year.

Then, for each region, ICF calculated the ratio of the industrial demand to total storage capacity available for a storage price of less than zero dollars per ton (that is, the parts of storage cost curves made up of EOR opportunities where the benefit of incremental oil production exceeded the storage costs). An upper limit of $0.00 per ton was chosen under the belief that the earliest uses of CO_2 from industrial sources most likely would continue the current practice of targeting EOR opportunities. Converting this quantity of capacity reserved for industrial CCS to a percent value and subtracting from 100 percent, ICF obtained the percent of storage capacity available to the electricity sector at less than zero dollars per ton. Finally, the Annual Step Bound (MMTons) and Total Storage Capacity (MMTons) was multiplied by this percentage value for each step below zero dollars[70] in the cost curves for the region to obtain the reduced storage capacity that went into the storage cost curves for the electric sector in EPA Platform v6. Thus, the values shown in Table 6-4 represent the storage available specifically to the electric sector after subtracting an amount that might be used by the industrial sector.

The price steps in the Table 6-4 are the same from region to region. (That is, STEP9 [column 2] has a step cost value of $9.64/Ton [column 3] across all storage regions [column 1]. This across-region price equivalency holds for every step.) However, the amount of storage available in any given year (labeled Annual Step Bound (MMTons) in column 4) and the total storage available over all years (labeled Total Storage Capacity (MMTons) in column 5) vary from region to region. In any given region, the cost curves are the same for every run year, indicating that over the modeling time horizon no new storage is being identified to augment the current storage capacity estimates. This assumption is not meant to imply that no additional potential storage capacity could be identified by NATCARB or another organization. Such future capacity discoveries could be represented in the model if model runs exhaust key components of the currently estimated storage capacity.

6.3 CO_2 Transport

Each of the 64 IPM model regions can send CO_2 to the 41 regions represented by the storage cost curves in Table 6-4. The associated transport costs (in 2019$/Ton) are shown in Table 6-5. For the model, ICF has also updated assumptions about the costs of CO_2 pipelines. These costs were derived by first calculating the pipeline distance from each of the CO_2 Production Regions to each of the CO_2 Storage Regions listed in Table 6-4. CO_2 transportation costs are based on a pipeline cost of $228,000 per inch-mile which is consistent with the EPA Platform v6 natural gas supply curve and basis differential assumptions from GMM. The costs also assume a 12-inch pipeline with a minimum distance of 100 miles.

List of tables that are uploaded directly to the web:

Table 6-4 CO_2 Storage Cost Curves in EPA Platform v6 2022 Reference Case

Table 6-5 CO_2 Transportation Matrix in EPA Platform v6 2022 Reference Case

Attachment 6-1 CO_2 Reduction Retrofit Cost Development Methodology

[70] Zero and negative cost steps represent storage available from enhanced oil recovery (EOR) where oil producers either pay or offer free storage for CO_2 that is injected into mature oil wells to enhance the amount of oil recovered. The value of the CO_2 for EOR is calculated using the average price of crude oil of $75/bbl. There is also a small market for CO_2 injection in enhanced coal bed methane (ECBM) production. ECBM is excluded from EPA's inventory as discussed earlier.